# DR. ARTHUR M. SQUIRES
# RECIPIENT OF
# 1973 STORCH AWARD

## THE HENRY H. STORCH AWARD

Friends of Dr. Henry H. Storch established the Award in 1964 as a memorial to him for his outstanding achievements as a physical chemist and a research director. Dr. Storch's major work involved fundamental research on the chemistry of coal and on engineering studies of coal utilization. Much of this work was accomplished while he was director of research at the U. S. Bureau of Mines from 1928 to 1951. The Award, administered by the Division of Fuel Chemistry, is given annually to a U. S. citizen who has contributed most to fundamental or engineering research on the chemistry and utilization of coal, or related materials, in the preceding five years. The Award consists of a plaque and an honorarium of $100, which are presented at the Fall National Meeting of the American Chemical Society.

## Biography

Arthur M. Squires is Professor and Chairman, the Chemical Engineering Department of the City College of the City University of New York. There he heads a fifteen-man research team working under a grant from the RANN Program (of the National Science Foundation) to convert coal into clean fuels.

Born in Neodesha, Kansas (March 21, 1916), he completed elementary and high school in Higginsville and Columbia, Missouri, respectively. In 1938, the University of Missouri granted him an A.B. with distinction in chemistry. In 1947, he obtained a Ph.D., in physical chemistry, under the late John Kirkwood at Cornell University.

Dr. Squires' interest in engineering was aroused during World War II through his association with Manson Benedict, now of M.I.T., whom he assisted in the process design of the Oak Ridge gaseous diffusion plant for concentrating Uranium-235. Subsequently he became Assistant Director (1946-1951) and Director (1951-1959) of Process Development at Hydrocarbon Research, Inc., where he worked on producing synthesis gas from natural gas, fuel oil, and coal. From 1959 to 1971, he served as a consultant to various chemical process industries. In 1967, Dr. Squires joined the faculty of Chemical Engineering, City College of the City University of New York as a full Professor; and in 1970 he was elected Chairman of the Department.

Dr. Squires holds sixteen U. S. patents dealing with fuel processing, gas cleaning, fluid-particle technology, and power generation; and he has published more than thirty papers in these fields.

Dr. Squires is a member of various chemical and engineering societies, here and abroad, and is a Fellow of the American Association for Advancement of Science. Among his committee memberships are: Committee on Environmental Alteration, and Ad Hoc Committee of the American Society of Mechanical Engineers for Setting Goals for Energy Research.

For many years, Dr. Squires has had a deep interest in the arts, particularly music. He played a leading role in the formation of New York Pro Musica and is a member of its board of directors. He was a soloist for the group, and even now finds time for singing lessons. In addition, he plays the harpsichord for relaxation.

THE DIVISION OF FUEL CHEMISTRY
HENRY H. STORCH AWARD

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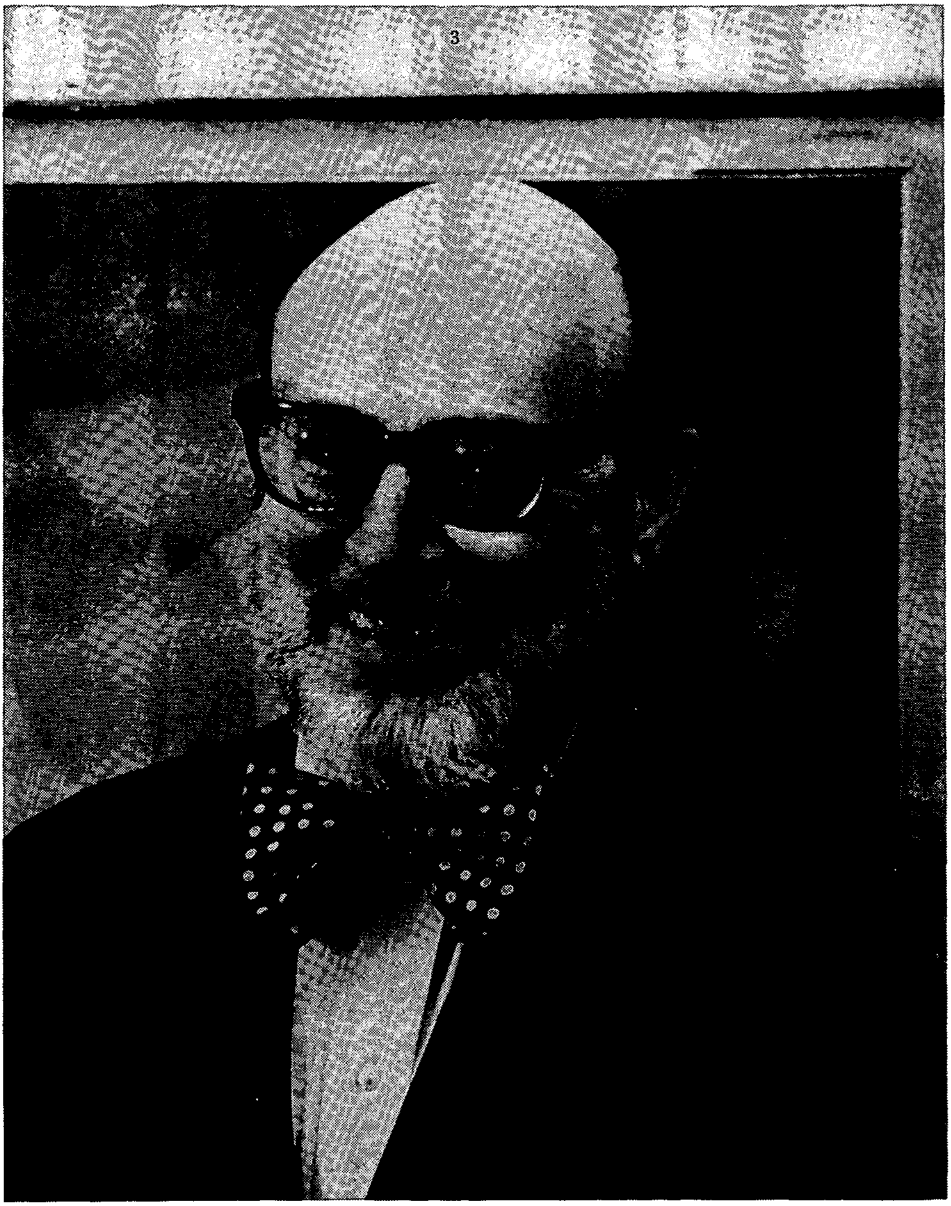

Gasifying Coal in High-Velocity Fluidized Beds, Arthur M. Squires, Department of Chemical Engineering, The City College of The City University of New York, New York, New York 10031

Two distinct arts of fluidization arose independently from (1) Winkler's 1922 invention for gasifying crushed coal fluidized at about 15 ft/sec, and from (2) Lewis and Gilliland's discovery in 1938 that a bed of a fine catalyst remained "stationary" when fluidized at 1 ft/sec even though this was beyond the Stokes-Law settling velocity for the powder.

(1) Development of the first art led to processes treating crushed solids of natural origin; also, to agglomerating beds of two kinds: (a) accreting beds that produce dense beads, and (b) the Godel ash-agglomerating bed.

(2) Development of the second art led to higher velocities in both regenerator and cracking zone of the fluid cracker. Recently Lurgi has shown that a "fast fluidized bed" of a fine powder recirculating at 10 to 15 ft/sec displays good thermal communication between an exothermic zone near the bottom of a column and endothermicity elsewhere in the column.

Experiments and concepts for gasifying coal in fluidized beds will be reviewed in light of the two fluidized-bed arts. It appears that high-velocity beds will have many advantages for producing low-Btu gas to serve gas turbines in combined-cycle power systems.

# SULFUR REMOVAL FROM HOT PRODUCER GAS

by

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## INTRODUCTION

To obtain clean gas from coal, gasification and gas cleanup must be considered jointly in view of today's clean environment regulations. Much of the coal sulfur appears in the gas, and in addition, solid and tar particulates are present in concentrations that vary with the gasification process and coal composition. All gasification concepts undergoing development include some type of gas cleaning. Conventional practice could be followed using commercial equipment, but this requires gas cooling and scrubbing with liquid solutions. Disposal of liquid and solid wastes is required, and provision for recovering coal tar is necessary.

Low-Btu fuel gas for power generation is receiving serious consideration by the electric utilities because it offers a timely solution to the shortage of low-sulfur fuel. High-sulfur coals can be converted into gas and cleaned of sulfur before being burned for power generation. Commercialization of this practice will make large quantities of high-sulfur coal available for generating electricity. Probably the least complicated system for converting coal into low-Btu fuel gas is pressure gasification using mine-run coal which may have any free-swelling index from low to high and includes lignite.

Gasification in a fixed bed has been widely used commercially for over one hundred years and is still used today. Historically, the fixed-bed gas producer has required a feed of noncaking, lump-sized coal or coke. Recently, the Bureau of Mines at Morgantown, W. Va., has gasified many coals including strongly caking Pittsburgh seam (1),[1/] high-volatile A bituminous (FSI 8-1/2), and coal 50 percent smaller than 1/4-inch screen size (run-of-mine) (2). These pioneering developments have demonstrated that deep, continuous stirring or agitation of the fuel bed is essential and beneficial to the gasification process. The bed stirring promotes gasification reactions and gas quality by breaking massive coke formations and maintaining permeability of the bed for better contact between gas and fuel. The stirring employed in this work is much more extensive than ever used previously, and it warrants being distinguished by being called the stirred fixed-bed, or simply the stirred bed to distinghish it from the conventional fixed bed.

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1/ Underlined numbers in parentheses refer to items in the list of references at the end of this paper.

The Morgantown Energy Research Center of the U.S. Bureau of Mines has evaluated many solid sorbents as an acceptor for hydrogen sulfide in hot producer gas. Results of those studies using simulated producer gas at 1,000° to 1,500° F have been reported in earlier papers (3)(4). This paper reports results obtained with a sintered iron oxide sorbent and gas from the stirred-bed producer.

## EXPERIMENTAL

A mixture of iron oxide (hematite $Fe_2O_3$) and fly ash was the best sorbent found among more than thirty-two materials tested. Primary requirements were that the sorbent be readily available and relatively inexpensive, have reasonable sorption capacity and useful life, be easily regenerated for repeated use, and resist fusion or disintegration over the useful temperature range. Fly ash (as received) could be formed into a durable and regenerable sorbent, but its sorption capacity was improved by adding iron oxide, increasing the concentration to 36 percent from 15 percent originally present. Other oxides found in this fly ash but inactive included silica 35 percent, alumina 18 percent, and small percentages of oxides of calcium, magnesium, sodium, potassium, and titanium. Iron oxide concentrations greater than 40 percent were unsatisfactory because the bed fusion temperature was lowered and fusion took place during normal operations.

Pilot quantities of the fly ash-iron oxide sorbent were made by two catalyst manufacturers by mulling and extruding the mixture to form 1/4-inch-diameter cylinders with 1/4- to 3/8-inch lengths, which were then sintered to develop hardness. Mercury porosimeter measurements showed pore volume of one new sorbent was 0.36 cc per gram, but this decreased to 0.13 cc per gram and remained constant after 30 regenerations, as shown in figure 1. Surface area measured by nitrogen absorption ranged from 4.2 to 6.5 square meters per gram.

## RESULTS AND DISCUSSION

Two sorption-regeneration cycles were completed, cleaning gas generated by the stirred-bed producer using Upper Freeport coal. Gas composition is given in figure 2. Gas from the producer was transferred to the sorbent bed at system pressure of 120 psig via a heated pipeline. Bed temperatures were controlled to give 1,100° and 1,200° F, and flow rates were adjusted to give gas hourly space velocities of 710 and 940, respectively. Hydrogen sulfide concentration averaged 380 grains per 100 scf, and the gas contained approximately 1/2 pound of dust, 1 pound of tar, and 5 pounds of steam per 1,000 scf. Figure 3 shows hydrogen sulfide in the gas leaving the sorbent bed had its concentration reduced to 10 and 20 grains per 100 scf and did not increase until after six hours on steam. Removal was 95 percent and 97 percent effective with respect to hydrogen sulfide. Tar was not removed by the sorbent.

Data were obtained for cleaning the gas from Western Kentucky No. 9 coal using 820 hourly space velocity. Average $H_2S$ concentrations in the feed gas were 588, 518, and 478 grains per 100 cubic feet and respective bed temperatures were 1,100°, 1,200°, and 1,300° F. Sorption capacity increased markedly as bed temperature increased. Figure 4 shows the grams of $H_2S$ removed per gram of sorbent until concentration in gas leaving the bed reached 100 grains per 100 scf. The amount removed increased linearly between 1,100° and 1,300° F. Breakthrough was reached after approximately 4-1/2, 6, and 6-1/2 hours, respectively.

Reaction mechanism is chemisorption, whereby hydrogen sulfide diffuses throughout the sorbent and reacts with $Fe_2O_3$ forming FeS and $FeS_2$. Analyzing the spent sorbent indicated the empirical composition was $FeS_{1.3}$. Iron oxide, $Fe_2O_3$, was regenerated and the sulfur released as $SO_2$ by passing air or oxygen over the hot bed. With oxygen regeneration, the effluent gas was pure $SO_2$ until some oxygen passed through unreacted after regeneration was 90 percent complete.

## CONCLUSIONS

Sintered sorbent made of iron oxide and fly ash is effective for removing hydrogen sulfide at temperature up to 1,500° F. Long life is indicated for this sorbent when used in a fixed bed. Its activity is good for the 1/4-inch-diameter extrusion, the only size for which data were obtained, but reduction in size should increase its activity.

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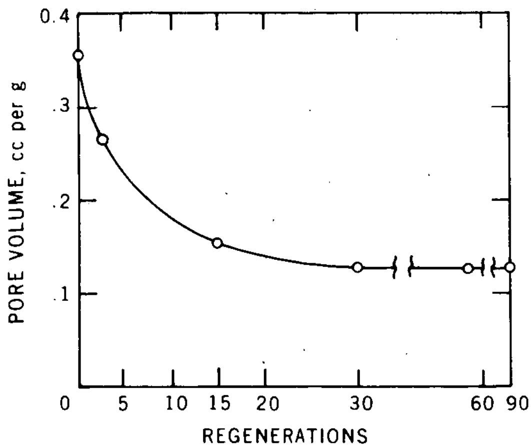


FIGURE 1.-Pore Volume Reaches Constant Value After 30 Regenerations

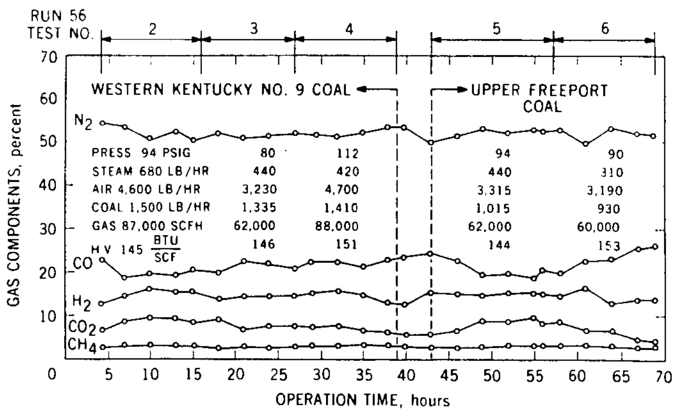


FIGURE 2. - Producer Gas Composition

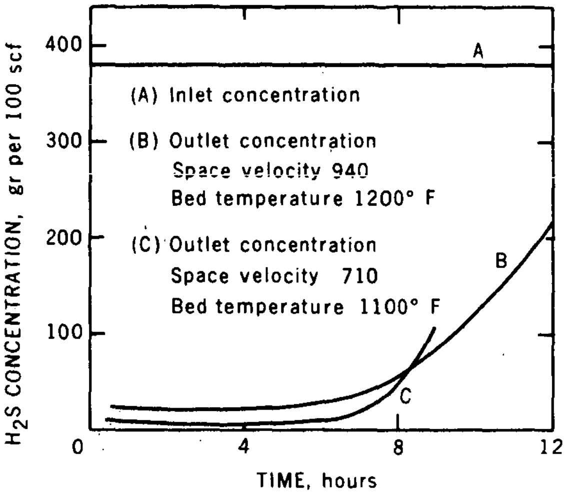


FIGURE 3. - Removing $H_2S$ from Producer Gas

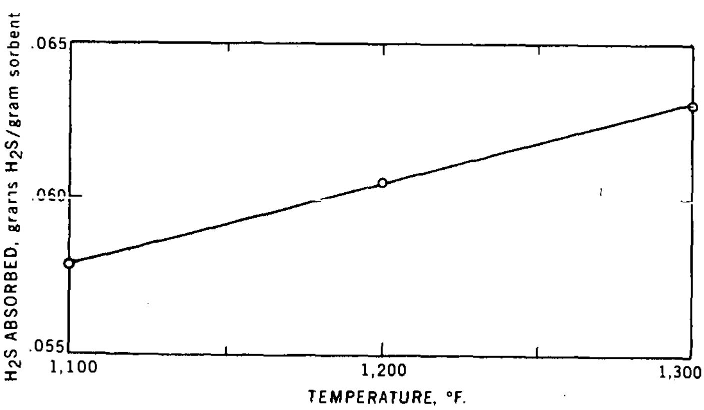


FIGURE 4. - Total $H_2S$ Absorbed by an $Fe_2O_3$ Fly Ash Bed Until 100 grains/100 $ft^3$ Breakthrough Occurred

The Panel Bed Filter for Simultaneous Removal of Dust and Sulfur,
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An old idea is to treat a gas by causing it to flow in the horizontal direction across a bed of a granular solid disposed in a tall, narrow "panel". The bed may be held in place, for example, by louvered walls that resemble venetian blinds.

Efficiencies beyond 99.99% have been measured for removal of redispersed fly ash from air at normal temperature. After a test, fly ash filter cake and a controlled amount of filter solid are removed by applying a surge backflow of gas from the clean side of the panel.

The paper will discuss problems yet to be faced in scaling up the device to commercial size and in projecting its performance at high temperatures, where a reactive filter solid might be used to remove sulfur species as well as dust.

# Coal for Peak Power

Henrik Harboe

STAL-LAVAL (Great Britain) Ltd.

In the ensuing debate about new forms of coal utilisation for power generation the attention has - often wrongly - been focused on mid load and base load plant but, it is most important also to look carefully at the problem of using coal for the generation of peak power.

Large variations in demand between night and day produce problems that the generating industry will always have to live with. This means that a lot of plant must be capable of stopping and starting once or twice in every day - with the associated need for changing the load of the installed capacity over large areas very rapidly. The giant-size base-load steam plants now being installed do not have these essentially flexible characteristics, and yet they will be required to meet such exacting duties if they - in the traditional way - are shifted down in the merit order as they get old. The alternatives are either to dissipate - during the night - some of the generated electricity as heat (seriously being put forward in some circles as the only practical, low-cost, method of dealing with the problem) or to tackle the overall question of reconciling generation method with load pattern.

One most effective course that can be adopted fills up the night time troughs in the demand curves by the introduction of power storage. Hydro-pumped power storage is an established technique that will soon reach the end of its limited exploitation potential and, quite naturally, it becomes more expensive as the less and less obvious sites are taken over and developed. An alternative method uses the storage of air under pressure, a technique that has not yet been exploited but which, because it will develop from known and tried techniques, shows excellent promise. Air storage power as such does not require large forward strides or jumps in technology, it is only a matter of marrying two known, experienced, branches of engineering: building and operating large industrial gas-turbines and the techniques of forming large underground caverns by mining, tunnelling, or leaching.

Up to 20% of the installed capacity of some power systems could in the future be air storage power and it is therefore necessary, already now, to look at the various possibilities for using coal as the primary fuel for such plant.

Fig. 1 shows by way of an example what can be achieved by employing a substantial amount of air storage power. Fig. 1a shows the 24 hour variation in electricity demand for a U.S. utility. The horizontal lines indicate the contribution of the various generating units on the system: several big units have to be turned down very severely every night and a large number of units have to be stopped and started every day.

By contrast has been shown on Fig. 1b the load pattern which the conventional plants would have to follow - the bold line - if 20% of the installed capacity was provided by six air storage units. These units would generate, on average, 8 hours per day. Assuming that our total installed capacity will increase fivefold between 1970 and year 2000, we see that air storage plants in year 2000 could represent as much capacity as we had installed in total in 1970 and the electrical energy generated by these plants could be well over half of our total 1970 production.

The principle of air storage power requires the use of gas-turbine equipment where the compressor(s) can be separately driven by an electric motor at such times as surplus, and therefore cheap, electricity supplies are available. Excess electricity production at night from ultra-large generating sets which must be run continuously and cannot be shut down or controlled on a divided-day basis is becoming very freely available and will become a serious "disposal problem" as nuclear plants proliferate. Air storage provides a use for this surplus production and a most economic method of using gas-turbines to cater for peak demands in day time.

During the day compressed air from storage is taken to the combustion chambers where it is heated up and then expanded through the turbine component to produce peak power. With this arrangement approximately three times as much day time output is available from an equal-capacity gas turbine installation than in the normal way - when two-thirds of the turbine output is needed to drive the compressor. Today, gas-turbines having 70 to 80 MW output are in routine production and use. It is a simple and straightforward matter to extend this to the construction of air storage units of 200 to 300 MW.

It is not the intention of this paper to draw comparisons between hydro-pumped storage power and air-storage power; such comparisons can only be made in specific cases where the authority concerned is fortunate enough to have a choice available in a given power system area.

This is an examination of air-storage power compared with conventional gas-turbines with and without steam turbines in combined-cycle installations. For these two main considerations there are the added alternatives of fuelling by High-Btu gas and Low-Btu gas derived from coal. As a major consideration, these two fuels are compared with the direct combustion of coal in a fluidised-bed air heater operating in conjunction with air-storage plant.

The need to improve the efficiency of open cycle gas-turbines and combined cycle units is forcing designers of gas-turbines to strive for inlet temperatures of well over 2000 °F. In turn, this demands a clean fuel and we see how - with coal as the main fossil fuel - this has lead to all the interest in coal gasification and low-Btu gas in particular.

Although an air-storage plant is basically a gas-turbine - albeit used in a very special way - there is not the same demand for very high turbine inlet temperatures. An economical analysis - which is not gone into here - shows that it is more rewarding to go to high storage pressures. Since a very high turbine inlet temperature is not a prerequisite for a good air-storage plant it has been natural to study the possibility of using coal fired fluidised bed air heaters instead of going the detour around coal gasification.

The simplest form of gas-turbine combined with a fluidised-bed heater is seen in Fig. 2. The air from the compressor is divided into two streams: primary combustion air, about 30 per cent of the total, goes through the bed, providing 10 to 20 per cent excess air for the combustion. This leaves the bed at 1600 °F (870 °C) after which it passes through two stages of cyclone separation.

Secondary air is passed through a closed-tube bundle immersed in the bed and is heated to 1427 °F. (775 °C); this bed-cooling air is mixed with the cyclone-separated air before entering the turbine at an average temperature of 1472 °F (800 °C).

By today's standard 1472 °F is a very conservative inlet temperature, but at a bed temperature of 1600 °F fluidised bed combustors have optimum performance: maximum sulphur removal by absorption into limestone or dolomite fuel additives, low vapour pressure of the alkali component in the ash and no melting of the ash. At this temperature the formation of nitrous oxides is low and particularly so when the combustion takes place under pressure as in this proposal.

This concept of a coal burning gas turbine is radically different from previous attempts to burn coal in gas-turbines. Firstly the feed consists of crushed coal in pea-sized lumps of which only a small amount is inadvertently reduced to dust. Previously, all the fuel was pulverised specially and expensively. There is now, therefore, a much smaller amount of airborne particles to be separated from the exhaust gases before these are passed to the turbine. It is also of importance that these particles have not been sintered whereas, previously, all fuel passed through the intensely hot high-temperature combustion zone, where all the ash was sintered and became highly abrasive, before being cooled by dilution air. Thirdly there is not now a corrosion problem superimposed on the erosion problem since, due to the lower temperature, the vapour pressure of the alkali component of coal ash in a fluidised bed is only a small fraction of that in conventional combustion systems. The cyclones, finally, have to deal with only one third of the mass flow compared with previous systems.

For air storage plant, where the air compression is done separately during the night, the specific fuel consumption during the day is barely influenced by the turbine inlet temperature - with reasonable preheating of the air from the storage cavern it will be around 4600 Btu/kWh.

A proposal for an air storage plant incorporating a pressurised fluidised bed air heater is shown on Fig. 3. If a storage pressure as high as 50 atmosphere is used it is natural to introduce reheat and let the actual combustion take place at about 10-12 atmosphere pressure. All the cold air from the storage cavern is preheated in an exhaust heat recouperator, it then passes through a high pressure tube bundle in one section of the fluidised bed where it is heated and subsequently expanded through a high-pressure air turbine. After the H.P. turbine the air is divided in two flows, as in the simple gas-turbine arrangement, with one stream going through cooling tubes to be reheated before joining the exhaust gases and expanded through the low-pressure turbine.

The air mass flow of this proposed 260 MW reheat air storage plant corresponds to the mass flow of a 70 MW conventional gas-turbine now in production. This gives an idea of how much more the hardware is utilised in an air storage arrangment.

In the following, very coarse, comparison of the cost of an air-storage-fluidised bed-air-heater with other alternatives is made a number of assumptions and the results are shown in a diagram, Fig. 4 :

| | | |
|---|---|---|
| - | capital cost of gas turbines | $ 100/kW |
| - | capital cost of combined cycle | $ 135/kW |
| - | capital cost of air storage plant: | |
| | "above ground" | $ 75/kW |
| | storage cavern: "0" hour/day | $ 25/kW |
| | 12 " /day | $ 65/kW |

- capital cost of high-Btu gas plant supplying a generating station which uses 10,000 Btu/kWh — \$ 250/kW

- capital cost of low-Btu gas plant supplying a generating station which uses 10,000 Btu/kWh — \$ 125/kW

- The capital cost of fluidised bed air heaters have been studied in some depth and the best estimate now is that a fluidised bed air heater with all coal and ash handling facilities will add \$ 40/kW to the cost of a 260 MW reheat air storage plant.

- gas turbine efficiency (for late 1970's) — 35%

- combined cycle efficiency — 46%

- efficiency of high-Btu gas plant — 70%

- efficiency of low-Btu gas plant — 85%

- cost of coal — 40 cent/MBtu

- capital charges — 15%

- Operating costs for air storage plant can be divided into two parts:-

  (a) The cost of night time energy supplies. With a night/day energy ratio of 0.66 (i.e. 0.66 kWh spent for compression of air for each 1 kWh generated during the day), and an assumed marginal fuel consumption for base load plants during the night of 9000 Btu /kWh, the cost for night night energy is 6000 Btu/kWh x the specific fuel cost. For simplicity it is considered that night time supplies of energy would at present come from coal-fired stations. Eventually, when night time energy is provided by nuclear plants, operating costs will be reduced still further - and make air storage even more competitive.

  (b) The cost of fuel used during the day. The direct day time fuel consumption - also called the in situ fuel consumption - can be 4600 Btu/kWh.

Therefore, a + b = 6000 + 4600 = 10,600 Btu/kWh, which is the total primary fuel consumption needed by an air storage plant using a fluidised-bed air heater. This is the fuel consumption which is used here as the reference value for all comparisons.

- variations in fuel consumption for different alternatives are converted to capital cost equivalent so that all comparisons can be done on capital cost diagrams alone. This is possible when the same initial fuel is used throughout.

- high-Btu gas will be produced on a continuous basis in large plants and stored for use intermittently by peak power plants. Therefore the capital cost for gas making plant is taken in proportion to the number of hours per day - out of 24 - which the peak load plant is intended to operate.

- low-Btu gas will be produced at power station site when needed, partly because it is "bulky" and partly to avoid the losses in cooling it down for storage. Designers of low-Btu gas plants should note that such plant will be required to stop and start every day!

The specific capital cost figures used in Fig. 4 to correct for variations in primary (i.e. coal) fuel consumption has been worked out in the following tables: I, II and III. 12 hours per day is used as reference time (12 hours per day during 11 month corresponds to 4000 hours per year). At zero hours per day there is of course no adjustment.

Table I

Air Storage

| | | Fluidised Bed * | High-Btu Gas | Low-Btu Gas |
|---|---|---|---|---|
| Indirect night fuel, | Btu/kWh | 6000 | 6000 | 6000 |
| Primary day fuel, | - " - | 4600 | 6600 | 5400 |
| Total | Btu/kWh | 10600 | 12600 | 11400 |
| Variation | - " - | Datum | +2000 | + 800 |
| $/kW at 4000 h/year (12h/day) | | Datum | + 21 | + 9 |

* Or natural gas or oil as fuel in conventional combustion chambers.

Table II

Gas Turbine (Secondary fuel consumption 9750 Btu/kWh)

| | Primary fuel consumption Btu/kWh | Compared with Air Storage Btu/kWh | $/kW at 4000 h/year |
|---|---|---|---|
| High-Btu gas : | 13,900 | + 3300 | + 35 |
| Low-Btu gas : | 11,500 | + 900 | + 10 |

Table III

Combined-Cycle Plant (Secondary fuel consumption 7400 Btu/kWh)

| | Primary fuel consumption Btu/kWh | Compared with Air Storage Btu/kWh | $/kW at 4000 h/year |
|---|---|---|---|
| High-Btu gas : | 10,600 | $\pm$ 0 | $\pm$ 0 |
| Low-Btu gas : | 8,750 | - 1850 | - 20 |

Looking now at Fig. 4 one sees in alternative "a" that an air storage plant for less than 6 hours operation per day should burn high-Btu gas if this can be produced on a large scale in a plant which operates continuously. But, for longer operating hours it pays to employ fluidised bed air heaters. For the demand curve shown on Fig. 1 this would mean three units gas fired and three units with fluidised bed air heaters - these last three units generating three times as much electricity as the first three.

In alternatives "b" and "c" is shown - in heavy broken line - for comparison the most economical air storage cost called "datum". Only combined cycle plant ("c") operating for more than 15 hours per day will be competitive with air storage plant - and then one is out of the peak load regime, but not necessarily out of the two-shift regime.

In summing up one can highlight a number of important features of air storage plant:

- it allows base load plant to be operated in a true base load mode by filling up the night trough in the demand.

- when built near load centres - as it should be - it then causes less air pollution than any other alternative: 4600 Btu/kWh in situ fuel consumption.

- its maximum output is not reduced at high ambient temperature - a problem with conventional gas turbines and combined cycle plant.

- it does not require excessive turbine inlet temperatures and is therefore well suited to its invariable duty of daily stops and starts.

- the relatively low turbine inlet temperature allows the use of fluidised bed air heater, which in turn makes it possible to use coal of very low and varying quality.

- the combination with fluidised bed air heaters does not alter the ability to stop and start every day: when air and fuel is cut off the bed will stay warm for days.

- it should be operated at nearly constant turbine inlet temperature - by throttling fuel and air simultaneously - and therefore shows very good part load efficiency.

In planning the development of new generating plant, using coal as the primary fuel, it is important to remember that none of the new ideas now being discussed will make an effective impact until we are well into the 1980's. In the mean time we see lots of large base load plant being put on stream - plant which will have to remain in a near base load mode of operation throughout its life. Nuclear power in particular will want to stay in the base load area - and towards year 2000 may account for 50% of all installed capacity. Altogether this makes it exceedingly important to guide the coal-power developments in such a direction that it allows these new breed of plant to operate in peak load and intermittent modes and air storage plant may prove very competitive in our endeavours to provide clean power from dirty fuel.

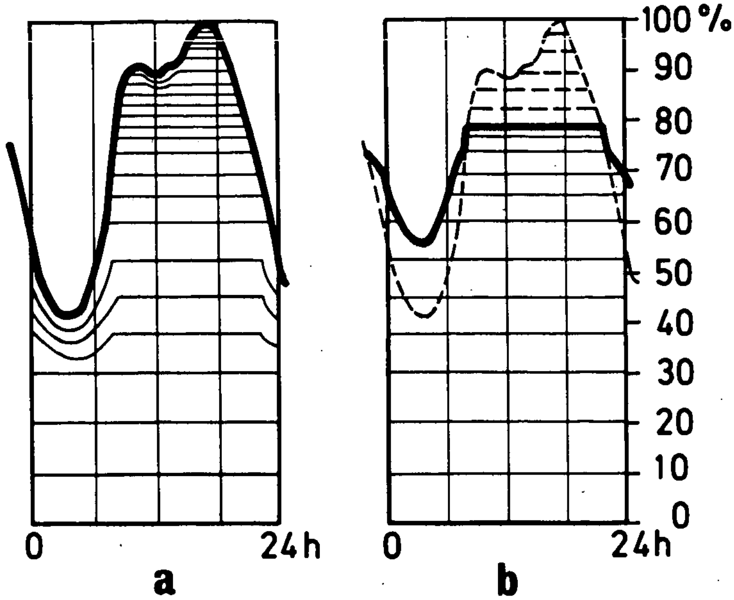



Fig. 1. Example of a daily load curve in an electricity supply system (a) and the effect of introducing 20% air storage power (b).

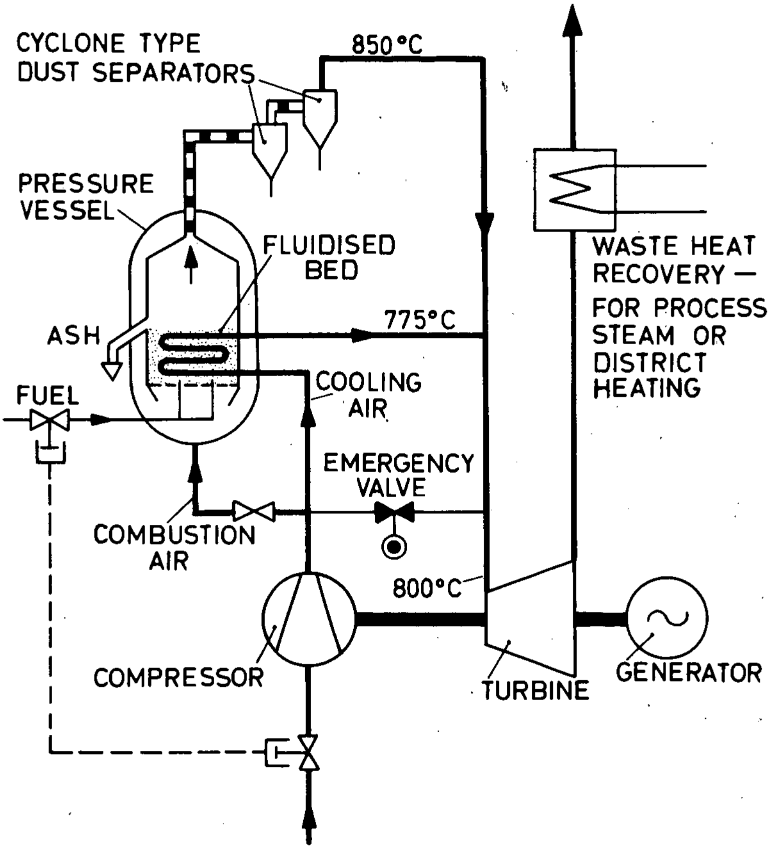
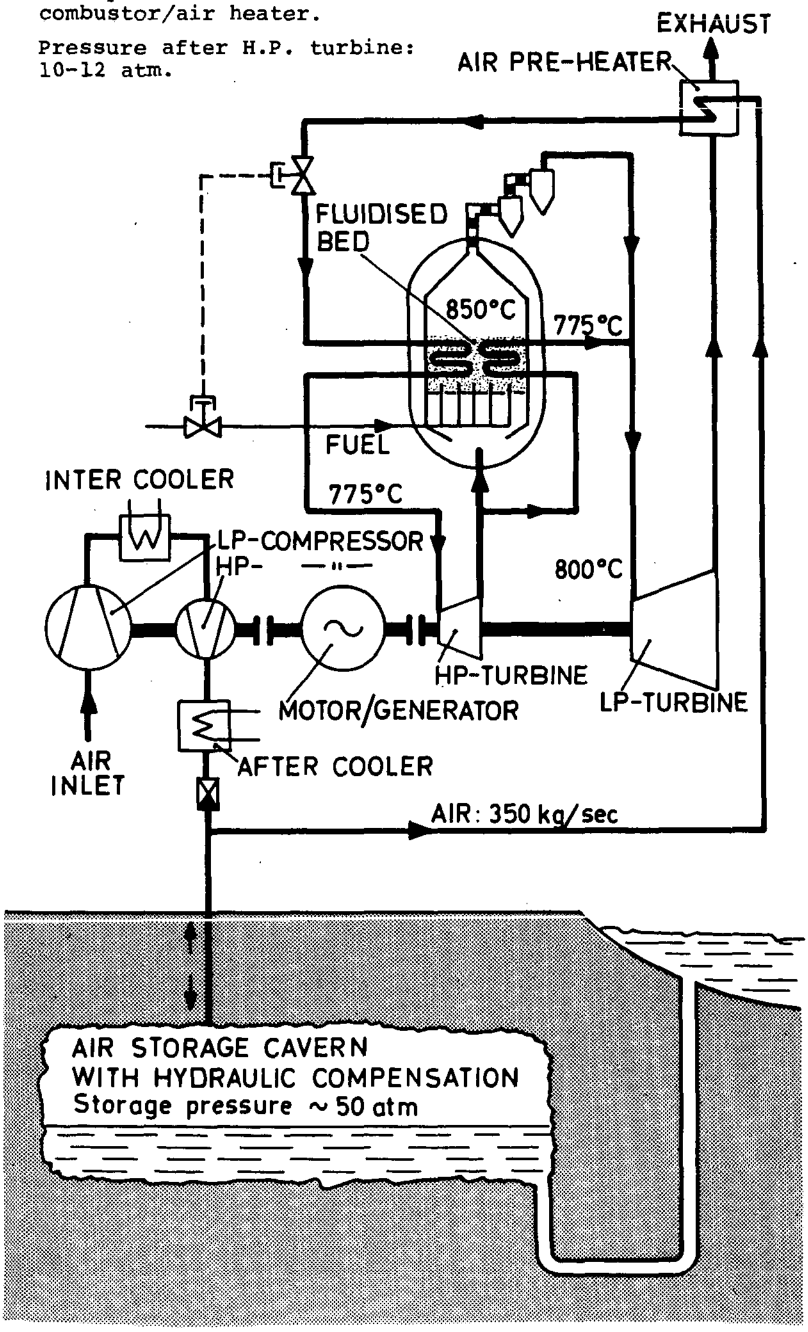



Fig. 2. Open cycle gas turbine with pressurised fluidised bed combustor/air heater.

Fig. 3.

260 MW reheat air storage plant with pressurised fluidised bed combustor/air heater.

Pressure after H.P. turbine: 10-12 atm.



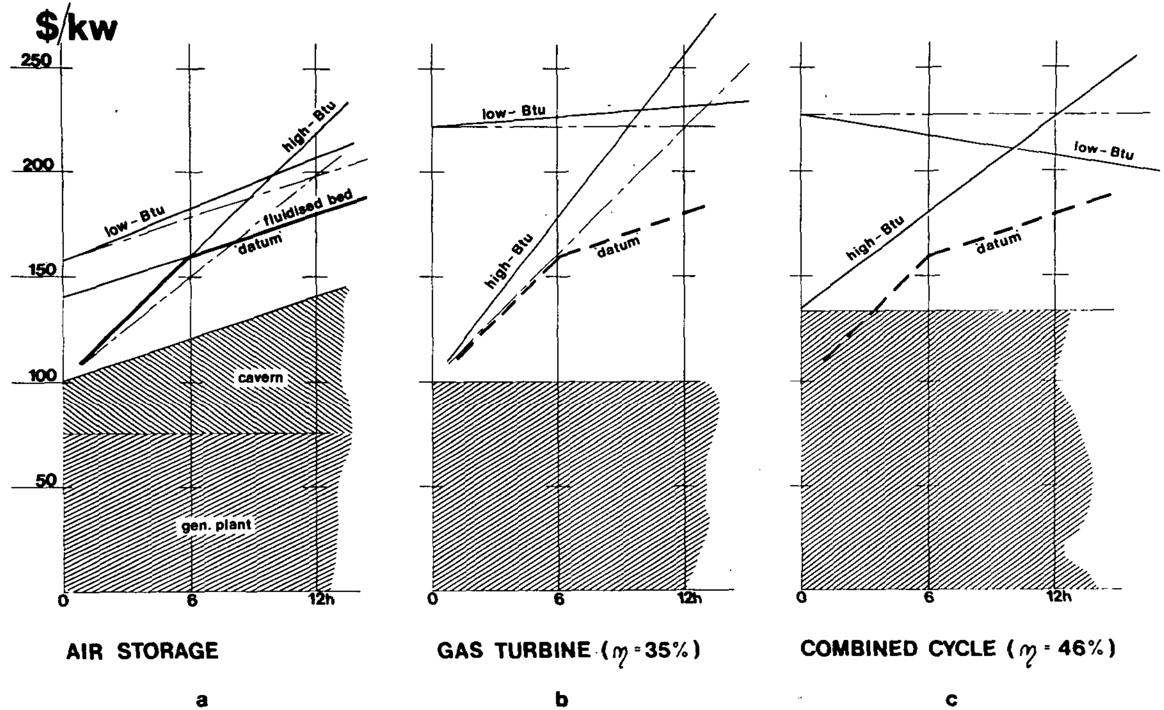



Fig. 4. Capital cost comparison of different types of peak power plant as function of operating hours per day. All using coal as primary fuel and all normalised to 10,600 Btu/kWh primary fuel consumption.